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## Power System Dynamic Modeling

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### 13.1 Modeling Requirements

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Analysis of power system dynamic performance requires the use of computational models representing the nonlinear differential–algebraic equations of the various system components. While scale models or analog models are sometimes used for this purpose, most power system dynamic analysis is performed with digital computers using specialized programs. These programs include a variety of models for generators, excitation systems, governor–turbine systems, loads, and other components. The user is therefore concerned with selecting the appropriate models for the problem at hand and determining the data to represent the specific equipment on his or her system. The focus of this article is on these concerns.

The choice of appropriate models depends heavily on the timescale of the problem being analyzed. [Figure 13.1](#) shows the principal power system dynamic performance areas displayed on a logarithmic timescale ranging from microseconds to days. The lower end of the band for a particular item indicates the smallest time constants that need to be included for adequate modeling. The upper end indicates the approximate length of time that must be analyzed. It is possible to build a power system simulation model that includes all dynamic effects from very fast network inductance/capacitance effects to very slow economic dispatch of generation. However, for efficiency and ease of analysis, normal engineering practice dictates that only models incorporating the dynamic effects relevant to the particular performance area of concern be used.

This section focuses on the modeling required for analysis of power system stability, including transient stability, oscillatory stability, voltage stability, and frequency stability. For this purpose, it is normally adequate to represent the electrical network elements (transmission lines and transformers) by algebraic equations. The effect of frequency changes on the inductive and capacitive reactances is sometimes included, but is usually neglected, since for most stability analysis, the frequency changes are small. The modeling of the various system components for stability analysis purposes is discussed in

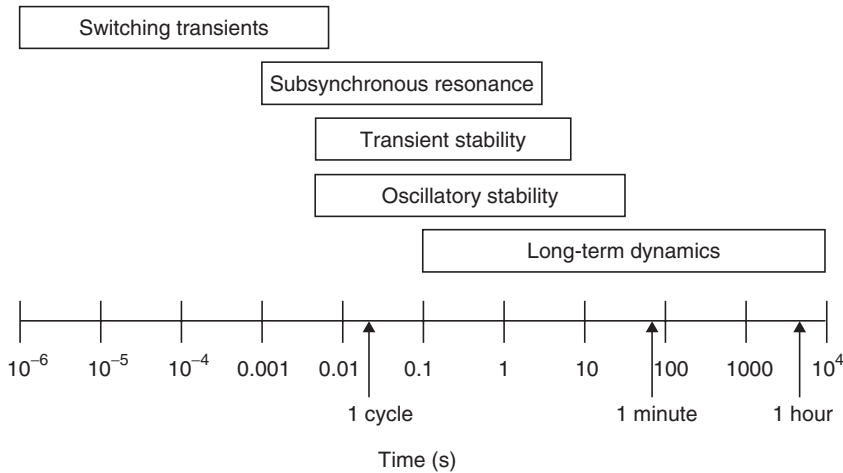


FIGURE 13.1 Timescale of power system dynamic phenomena.

the remainder of this section. For greater detail, the reader is referred to Kundur (1994) and the other references cited below.

## 13.2 Generator Modeling

The model of a generator consists of two parts: the acceleration equations of the turbine-generator rotor and the generator electrical flux dynamics.

### 13.2.1 Rotor Mechanical Model

The acceleration equations are simply Newton's second law of motion applied to the rotating mass of the turbine-generator rotor, as shown in block diagram form in Fig. 13.2. The following points should be noted:

1. The inertia constant ( $H$ ) represents the stored energy in the rotor in MW-seconds, normalized to the MVA rating of the generator. Typical values are in the range of 3 to 15, depending on the type and size of the turbine generator. If the inertia ( $J$ ) of the rotor is given in kg-m/s,  $H$  is computed as follows:

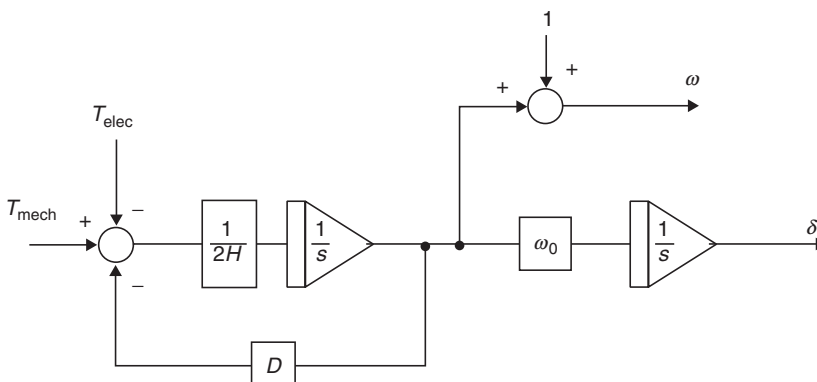


FIGURE 13.2 Generator rotor mechanical model.

$$H = 5.48 \times 10^{-9} \frac{J(\text{RPM})^2}{\text{MVA rating}} \text{MW-s/MVA}$$

2. Sometimes, the mechanical power and electrical power are used in this model instead of the corresponding torques. Since power equals torque multiplied by rotor speed, the difference is small for operation close to nominal speed. However, there will be some effect on the damping of oscillations (IEEE Transactions, February 1999).
3. Most models include the damping factor ( $D$ ), shown in Fig. 13.2. It is used to model oscillation damping effects that are not explicitly represented elsewhere in the system model. The selection of a value for this parameter has been the subject of much debate (IEEE Transactions, February 1999). Values from 0 to 4 or higher are sometimes used. The recommended practice is to avoid the use of this parameter by including sources of damping in other models, e.g., generator amortisseur and eddy current effects, load frequency sensitivity, etc.

### 13.2.2 Generator Electrical Model

The equivalent circuit of a three-phase synchronous generator is usually rendered as shown in Fig. 13.3. The three phases are transformed into a two-axis equivalent, with the direct (d) axis in phase with the rotor field winding and the quadrature (q) axis 90 electrical degrees ahead. For a more complete discussion of this transformation and of generator modeling, see IEEE Standard 1110-1991. In this equivalent circuit,  $r_a$  and  $L_l$  represent the resistance and leakage inductance of the generator stator,  $L_{ad}$  and  $L_{aq}$  represent the mutual inductance between stator and rotor, and the remaining elements represent rotor windings or equivalent windings. This equivalent circuit assumes that the mutual coupling between the rotor windings and between the rotor and stator windings is the same. Additional elements can be added (IEEE Standard 1110-1991) to account for unequal mutual coupling, but most models do not include this, since the data is difficult to obtain and the effect is small.

The rotor circuit elements may represent either physical windings on the rotor or eddy currents flowing in the rotor body. For solid-iron rotor generators, such as steam turbine generators, the field winding to which the DC excitation voltage is applied is normally the only physical winding. However, additional equivalent windings are required to represent the effects of eddy currents induced in the body

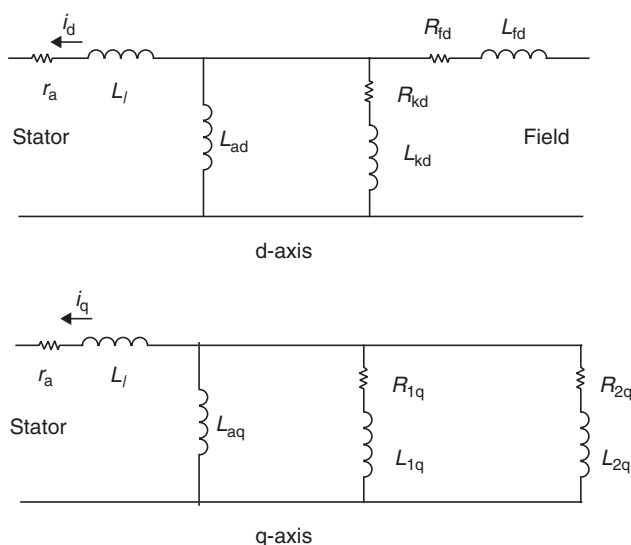


FIGURE 13.3 Generator equivalent circuit.

**TABLE 13.1** Generator Parameter Relationships

|                                         | d-axis                                                                                           | q-axis                                                                                           |
|-----------------------------------------|--------------------------------------------------------------------------------------------------|--------------------------------------------------------------------------------------------------|
| Synchronous inductance                  | $L_d = L_l + L_{ad}$                                                                             | $L_q = L_l + L_{aq}$                                                                             |
| Transient inductance                    | $L'_d = L_l + \frac{L_{ad}L_{fd}}{L_{ad} + L_{fd}}$                                              | $L'_q = L_l + \frac{L_{aq}L_{lq}}{L_{aq} + L_{lq}}$                                              |
| Subtransient inductance                 | $L''_d = L_l + \frac{L_{ad}L_{fd}L_{kd}}{L_{ad}L_{fd} + L_{ad}L_{kd} + L_{fd}L_{kd}}$            | $L''_q = L_l + \frac{L_{aq}L_{lq}L_{2q}}{L_{aq}L_{lq} + L_{aq}L_{2q} + L_{lq}L_{2q}}$            |
| Transient open circuit time constant    | $T'_{do} = \frac{L_{ad} + L_{fd}}{\omega_0 R_{fd}}$                                              | $T'_{qo} = \frac{L_{aq} + L_{lq}}{\omega_0 R_{lq}}$                                              |
| Subtransient open circuit time constant | $T''_{do} = \frac{L_{ad}L_{fd} + L_{ad}L_{kd} + L_{fd}L_{kd}}{\omega_0 R_{kd}(L_{ad} + L_{fd})}$ | $T''_{qo} = \frac{L_{aq}L_{lq} + L_{aq}L_{2q} + L_{lq}L_{2q}}{\omega_0 R_{2q}(L_{aq} + L_{lq})}$ |

of the rotor. Salient-pole generators, typically used for hydro-turbine generators, have laminated rotors with lower eddy currents. However, these rotors often have additional amortisseur (damper) windings embedded in the rotor.

Data for generator modeling is usually supplied as synchronous, transient, and subtransient inductances and open circuit time constants. The relationships between these parameters and the equivalent network elements are shown in Table 13.1. Note that the inductance values are often referred to as reactances. At nominal frequency, the per unit inductance and reactance values are the same. However, as used in the generator model, they are really inductances, which do not change with changing frequency.

These parameters are normally supplied by the manufacturer. Two values are often given for some of the inductance values, a saturated (rated voltage) and unsaturated (rated current) value. The unsaturated values should be used, since saturation is usually accounted for separately, as discussed below.

For salient-pole generators, one or more of the time constants and inductances may be absent from the data, since fewer equivalent circuits are required. Depending on the program, either separate models are provided for this case or the same model is used with certain parameters set to zero or equal to each other.

### 13.2.3 Saturation Modeling

Magnetic saturation effects may be incorporated into the generator electrical model in various ways. The data required from the manufacturer is the open circuit saturation curve, showing generator terminal voltage vs. field current. If the field current is given in amperes, it can be converted to per unit by dividing by the field current at rated terminal voltage on the air gap (no saturation) line. (This value of field current is sometimes referred to as AFAG or IFAG.) Often the saturation data for a generator model is input as only two points on the saturation curve, e.g., at rated voltage and 120% of rated voltage. The model then automatically fits a curve to these points.

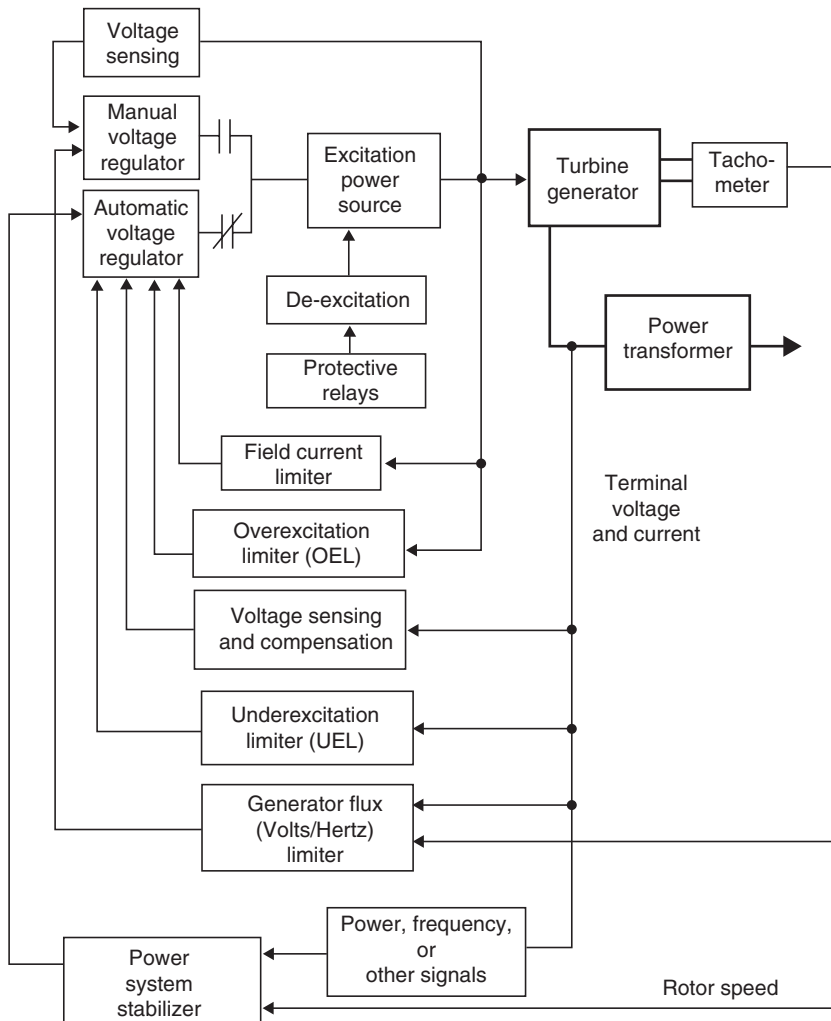
The open circuit saturation curve characterizes saturation in the d-axis only. Ideally, saturation of the q-axis should also be represented, but the data for this is difficult to determine and is usually not provided. Some models provide an approximate representation of q-axis saturation based on the d-axis saturation data (IEEE Standard 1110-1991).

## 13.3 Excitation System Modeling

The excitation system provides the DC voltage to the field winding of the generator and modulates this voltage for control purposes. There are many different configurations and designs of excitation systems.

Stability programs usually include a variety of models capable of representing most systems. These models normally include the IEEE standard excitation system models, described in IEEE Standard 421.5 (1992). Reference should be made to that document for a description of the various models and typical data for commonly used excitation system designs. This standard is periodically updated to include new excitation system designs.

The excitation system consists of several subsystems, as shown in Fig. 13.4. The excitation power source provides the DC voltage and current at the levels required by the generator field. The excitation power may be provided by a rotating exciter, either a DC generator or an AC generator (alternator) and rectifier combination, or by controlled rectifiers supplied from the generator terminals (or other AC source). Excitation systems with these power sources are often classified as “DC,” “AC,” and “static,” respectively. The maximum (ceiling) field voltage available from the excitation power source is an important parameter. Depending on the type of system, this ceiling voltage may be affected by the magnitude of the field current or the generator terminal voltage, and this dependency must be modeled since these values may change significantly during a disturbance.



**FIGURE 13.4** Excitation system model structure.

The automatic voltage regulator (AVR) provides for control of the terminal voltage of the generator by changing the generator field voltage. There are a variety of designs for the AVR, including various means of ensuring stable response to transient changes in terminal voltage. The speed with which the field voltage can be changed is an important characteristic of the system. For the DC and most of the AC excitation systems, the AVR controls the field of the exciter. Therefore, the speed of response is limited by the exciter's time constant. The speed of response of excitation systems is characterized according to IEEE Standard 421.2 (1990).

A power system stabilizer (PSS) is frequently, but not always, included in an excitation system. It is designed to modulate the AVR input in such a manner as to contribute damping to intermachine oscillations. The input to the PSS may be generator rotor speed, electrical power, or other signals. The PSS usually is designed with linear transfer functions whose parameters are tuned to produce positive damping for the range of oscillation frequencies of concern. It is important that reasonably correct values be used for these parameters. The output of the PSS is limited, usually to  $\pm 5\%$  of rated generator terminal voltage, and this limit value must be included in the model.

The excitation system includes several other subsystems designed to protect the generator and excitation system from excessive duty under abnormal operating conditions. Normally, these limiters and protective modules do not come into play for analysis of transient and oscillatory stability. However, for longer-term simulations, particularly related to voltage instability, overexcitation limiters (OEL) and underexcitation limiters (UEL) may need to be modeled. While there are many designs for these limiters, typical systems are described in IEEE Transactions (December and September, 1995).

## 13.4 Prime Mover Modeling

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The system that drives the generator rotor is often referred to as the prime mover. The prime mover system includes the turbine (or other engine) driving the shaft, the speed control system, and the energy supply system for the turbine. The following are the most common prime mover systems:

- Steam turbine
- Fossil fuel (coal, gas, or oil) boiler
- Nuclear reactor
- Hydro turbine
- Combustion turbine (gas turbine)
- Combined cycle (gas turbine and steam turbine)
- Wind turbine

Other less common and generally smaller prime movers include geothermal steam turbine, solar thermal steam turbine, and diesel engine.

For analysis of transient and oscillatory stability, greatly simplified models of the prime mover are sufficient since, with some exceptions, the response times of the prime movers to system disturbances are slow compared with the time duration of interest, typically 10 to 20 s or less. For simple transient stability analysis of only a few seconds duration, the prime mover model may be omitted altogether by assuming that the mechanical power output of the turbine remains constant. An exception is for a steam-turbine system equipped with "fast valving" or "early valve actuation" (EVA). These systems are designed to reduce turbine power output rapidly for nearby faults by quickly closing the intercept valves between the high-pressure and low-pressure turbine sections (Younkins et al., 1987).

For analysis of disturbances involving significant frequency excursions, the turbine and speed control (governor) systems must be modeled. Simplified models for steam and hydro-turbine-governor systems are given in IEEE Transactions (December 1973; February 1992) and these models are available in most stability programs. Models for gas turbines and combined cycle plants are less standard, but typical models have been described in several references (Rowan, 1983; Hannett and Khan, 1993; IEEE Transactions, August 1994).

For long-term simulations involving system islanding and large frequency excursions, more detailed modeling of the energy supply systems may be necessary. There are a great many configurations and designs for these systems. Models for typical systems have been published (IEEE Transactions, May 1991). However, detailed modeling is often less important than incorporating key factors that affect the plant response, such as whether the governor is in service and where the output limits are set.

For a fossil fuel steam plant, the coordination between the speed control and steam pressure control systems has an important impact on the speed with which the plant will respond to frequency excursions. If the governor directly controls the turbine valves (boiler-follow mode), the power output of the plant will respond quite rapidly, but may not be sustained due to reduction in steam pressure. If the governor controls fuel input to the boiler (turbine-follow mode), the response will be much slower but can be sustained. Modern coordinated controls will result in an intermediate response to these two extremes. The plant response will also be slowed by the use of “sliding pressure” control, in which valves are kept wide open and power output is adjusted by changing the steam pressure.

Hydro plants can respond quite rapidly to frequency changes if the governors are active. Some reduction in transient governor response is often required to avoid instability due to the “nonminimum phase” response characteristic of hydro turbines, which causes the initial response of power output to be in the opposite of the expected direction. This characteristic can be modeled approximately by the simple transfer function:  $(1 - sT_w)/(1 + sT_w/2)$ . The parameter  $T_w$  is called the water starting time and is a function of the length of the penstock and other physical dimensions. For high-head hydro plants with long penstocks and surge tanks, more detailed models of the hydraulic system may be necessary.

Gas (combustion) turbines can be controlled very rapidly, but are often operated at maximum output (base load), as determined by the exhaust temperature control system, in which case they cannot respond in the upward direction. However, if operated below base load, they may be able to provide output in excess of the base load value for a short period following a disturbance, until the exhaust temperature increases to its limit. Typical models for gas turbines and their controls are found in Rowan (1983) and IEEE Transactions (February 1993).

Combined cycle plants come in a great variety of configurations, which makes representation by a typical model difficult (IEEE Transactions, 1994). The steam turbine is supplied from a heat recovery steam generator (HRSG). Steam is generated by the exhaust from the gas turbines, sometimes with supplementary firing. Often the power output of the steam turbine is not directly controlled by the governor, but simply follows the changes in gas turbine output as the exhaust heat changes. Since the time constants of the HRSG are very long (several minutes), the output of the steam turbine can be considered constant for most studies.

### 13.4.1 Wind Turbine-Generator Systems

As large clusters of wind turbine generators (WTGs) become more widely installed on power systems, they must be included in system dynamic performance studies. This requires special modeling because the generation technologies used for WTGs differ significantly from the directly connected synchronous generators that are universally used for all of the other types of generation discussed above. There are four principal generation technologies in use for WTGs:

- Induction generator—a “squirrel-cage” induction machine operating at essentially constant speed as determined by the power available in the wind.
- Induction generator with controlled field resistance—a wound-rotor induction machine with external rotor resistance controlled electronically to permit some variation, e.g.,  $\pm 10\%$ , in rotor speed.
- Doubly-fed asynchronous generator—a wound-rotor induction machine with its three-phase field voltage supplied by a power electronic converter connected to the machine terminals. The field voltage magnitude and frequency are controlled to regulate terminal voltage and to vary the machine speed over a wide, e.g.,  $\pm 30\%$ , range.



- Full converter system—a generator connected to the system through a power electronic converter. The generator speed is decoupled from system frequency and can be controlled as desired, while the converter is used to regulate voltage and supply reactive power.

Computational models have been developed for each of these technologies, plus the electrical controls required by the latter three (Kazachkov et al., 2003; Koessler et al., 2003; Miller et al., 2003; Pourbeik et al., 2003). Most large WTGs also have blade pitch control systems that regulate shaft speed in response to wind fluctuations and electrical system disturbances. Several industry groups are working toward the development of standard models for each of these technologies.

For most studies, it is not necessary to represent the individual WTGs in a wind farm (cluster, park). One or a few aggregate machines can be used to represent the wind farm by the following procedures:

1. Aggregate WTG model same as individual but with MVA rating equal  $n$  times individual WTG rating
2. Aggregate generator step-up transformer same as individual but with MVA rating equal to  $n$  times individual transformer rating
3. Interconnection substation modeled as is
4. Aggregate collector system modeled as a single line with charging capacitance equal to total of the individual collector lines/cables and with series  $R$  and  $X$  adjusted to give approximately the same  $P$  and  $Q$  output at the interconnection substation at rated WTG output as the full system

## 13.5 Load Modeling

For dynamic performance analysis, the transient and steady-state variation of the load  $P$  and  $Q$  with changes in bus voltage and frequency must be modeled. Accurate load modeling is difficult due to the complex and changing nature of the load and the difficulty in obtaining accurate data on its characteristics. Therefore, sensitivity studies are recommended to determine the impact of the load characteristics on the study results of interest. This will help to guide the selection of a conservative load model or focus attention on where load modeling improvements should be sought.

For most power system analysis purposes, “load” refers to the real and reactive power supplied to lower voltage subtransmission or distribution systems at buses represented in the network model. In addition to the variety of actual load devices connected to the system, the “load” includes the intervening distribution feeders, transformers, shunt capacitors, etc., and may include voltage control devices, including automatic tap-changing transformers, induction voltage regulators, automatically switched capacitors, etc.

For transient and oscillatory stability analysis, several levels of detail can be used, depending on the availability of information and the sensitivity of the results to the load modeling detail. IEEE Transactions (May 1993 and August 1995) discuss recommended load modeling procedures. A brief discussion is given below:

1. *Static load model*—The simplest model is to represent the active and reactive load components at each bus by a combination of constant impedance, constant current, and constant power components, with a simple frequency sensitivity factor, as shown in the following formula:

$$P = P_0 \left[ P_1 \left( \frac{V}{V_0} \right)^2 + P_2 \left( \frac{V}{V_0} \right) + P_3 \right] (1 + L_{DP} \Delta f)$$

$$Q = Q_0 \left[ Q_1 \left( \frac{V}{V_0} \right)^2 + Q_2 \left( \frac{V}{V_0} \right) + Q_3 \right] (1 + L_{DP} \Delta f)$$

If nothing is known about the characteristics of the load, it is recommended that constant current be used for the real power and constant impedance for the reactive power, with frequency

factors of 1 and 2, respectively. This is based on the assumption that typical loads are about equally divided between motor loads and resistive (heating) loads.

Most stability programs provide for this type of load model, often called a ZIP model. Sometimes an exponential function of voltage is used instead of the three separate voltage terms. An exponent of 0 corresponds to constant power, 1 to constant current, and 2 to constant impedance. Intermediate values or larger values can be used if available data so indicates. The following, more general model, permitting greater modeling flexibility, is recommended in IEEE Transactions (August 1995):

$$P = P_0 \left[ K_{PZ} \left( \frac{V}{V_0} \right)^2 + K_{PI} \left( \frac{V}{V_0} \right) + K_{PC} + K_{PI} \left( \frac{V}{V_0} \right)^{npV1} \left( 1 + n_{PF1} \Delta f \right) + K_{P2} \left( \frac{V}{V_0} \right)^{npV2} \left( 1 + n_{PF2} \Delta f \right) \right]$$

$$Q = Q_0 \left[ K_{QZ} \left( \frac{V}{V_0} \right)^2 + K_{QI} \left( \frac{V}{V_0} \right) + K_{QC} + K_{QI} \left( \frac{V}{V_0} \right)^{nQV1} \left( 1 + n_{QF1} \Delta f \right) + K_{Q2} \left( \frac{V}{V_0} \right)^{nQV2} \left( 1 + n_{QF2} \Delta f \right) \right]$$

2. *Induction motor dynamic model*—For loads subjected to large fluctuations in voltage and/or frequency, the dynamic characteristics of the motor loads become important. Induction motor models are usually available in stability programs. Except in the case of studies of large motors in an industrial plant, individual motors are not represented. But one or two motor models representing the aggregation of all of the motors supplied from a bus can be used to give the approximate effect of the motor dynamics (Nozari et al., 1987). Typical motor data is given in the General Electric Company Load Modeling Reference Manual (1987). For analysis of voltage instability and other low voltage conditions, motor load modeling must include the effects of motor stalling and low-voltage tripping by protective devices.
3. *Detailed load model*—For particular studies, more accurate modeling of certain loads may be necessary. This may include representation of the approximate average feeder and transformer impedance as a series element between the network bus and the bus where the load models are connected. For long-term analysis, the automatic adjustment of transformer taps may be represented by simplified models. Several load components with different characteristics may be connected to the load bus to represent the composition of the load.

Load modeling data can be acquired in several ways, none of which are entirely satisfactory, but contribute to the knowledge of the load characteristics:

1. *Staged testing of load feeders*—Measurements can be made of changes in real and reactive power on distribution feeders when intentional changes are made in the voltage at the feeder, e.g., by changing transformer taps or switching a shunt capacitor. The latter has the advantage of providing an abrupt change that may provide some information on the dynamic response of the load as well as the steady-state characteristics. This approach has limitations in that only a small range of voltage can be applied, and the results are only valid for the conditions (time of day, season, temperature, etc.) when the tests were conducted. This type of test is most useful to verify a load model determined by other means.
2. *System disturbance monitoring*—Measurements can be made of power, voltage, and frequency at various points in the system during system disturbances, which may produce larger voltage (and possibly frequency) changes than can be achieved during staged testing. This requires installation and maintenance of monitors throughout the system, but this is becoming common practice on many systems for other purposes. Again, the data obtained will only be valid for the conditions at the time of the disturbance, but over time many data points can be collected and correlated.
3. *Composition-based modeling*—Load models can also be developed by obtaining information on the composition of the load in particular areas of the system. Residential, commercial, and various types of industrial loads are composed of various proportions of specific load devices.

The characteristics of the specific devices are generally well known (General Electric Company, 1987). The mix of devices can be determined from load surveys, customer SIC classifications, and typical compositions of different types of loads (General Electric Company, 1987).

## 13.6 Transmission Device Models

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For the most part, the elements of the transmission system, including overhead lines, underground cables, and transformers, can be represented by the same algebraic models used for steady-state (power flow) analysis. Lines and cables are normally represented by a pi-equivalent with lumped values for the series resistance and inductance and the shunt capacitance. Transformers are normally represented by their leakage inductance, resistance, and tap ratio. Transformer magnetizing inductance and eddy current (no-load) losses are sometimes included.

Other transmission devices that require special modeling include high-voltage direct current (HVDC) systems (Kundur, 1994) and power electronic (PE) devices. The latter includes static VAR compensators (SVC) (IEEE Transactions, February 1994) and a number of newer devices (TCSC, STATCON, UPFC, etc.) under the general heading of flexible AC transmission systems (FACTS) devices. Many of these devices have modulation controls designed to improve the stability performance of the power system. It is therefore important that these devices and their controls be accurately modeled. Due to the developmental nature of many of these technologies and specialized designs that are implemented, the modeling usually must be customized to the particular device.

## 13.7 Dynamic Equivalents

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It is often not feasible or necessary to include the entire interconnected power system in the model being used for a dynamic performance study. A certain portion of the system that is the focus of the study, the “study system,” is represented in detail. The remainder of the system, the “external system,” is represented by a simplified model that is called a dynamic equivalent. The requirements for the equivalent depend on the objective of the study and the characteristics of the system. Several types of equivalents are discussed below:

1. *Infinite bus*—If the external system is very large and stiff, compared with the study system, it may be adequate to represent it by an infinite bus, that is, a generator with very large inertia and very small impedance. This is often done for studies of industrial plant power systems or distribution systems that are connected to higher voltage transmission systems.
2. *Lumped inertia equivalent*—If the external system is not infinite with respect to the study system but is connected at a single point to the study system, a simple equivalent consisting of a single equivalent generator model may be used. The inertia of the generator is set approximately equal to the total inertia of all of the generators in the external area. The internal impedance of the equivalent generator should be set equal to the short-circuit (driving point) impedance of the external system viewed from the boundary bus.
3. *Coherent machine equivalent*—For more complex systems, especially when interarea oscillations are of interest, some form of coherent machine equivalent should be used. In this case, groups of generators in the external system are combined into single lumped inertia equivalents if these groups oscillate together for interarea modes of oscillation. Determination of such equivalents requires specialized calculations for which software is available (Price et al., 1996, 1998).

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